SUMMER 2008 ELECTRICITY SUPPLY AND DEMAND OUTLOOK

STAFF REPORT

Arnold Schwarzenegger, *Governor*

CALIFORNIA ENERGY COMMISSION

Denny Brown
Principal Author

Denny Brown
Project Manager

Al Alvarado
Manager
ELECTRICITY ANALYSIS OFFICE

Sylvia Bender
Deputy Director
ELECTRICITY SUPPLY ANALYSIS DIVISION

Melissa Jones
Executive Director

ABSTRACT

The *Summer 2008 Electricity Supply and Demand Outlook* provides a summary of the California Energy Commission staff's current assessment of the capability electricity system or grid to provide power to meet electricity demand in within California. The report also documents key assumptions and methodologies used to develop an assessment of physical resources. The Energy Commission requests input from interested parties for future analytical work.

KEYWORDS

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Barbara Crume
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Richard Jensen
Angela Tanghetti
Jim Woodward

Demand Analysis Office

Tom Gorin
David Hungerford
Lynn Marshall

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Introduction and Summary

The *Summer 2008 Electricity Supply and Demand Outlook* (*2008 Outlook*) provides a summary of the California Energy Commission (Energy Commission) staff assessment of the capability of the physical electricity system to meet peak electricity demand in California and three smaller geographic regions: the California Independent System (California ISO) Control Area, and the California ISO's northern and southern sub-regions.[1]

California is expected to have adequate electricity supplies to meet demand this summer even with hotter-than-average temperatures. California experienced the driest March-April combined since record-keeping began in 1921. Though the snow pack and forecast runoff are currently well below average, hydroelectric capacity will still be available to meet peak power needs.

Adequate supplies are ensured by having a 15-17 percent buffer of additional supplies above typical peak demand that are available to call upon as needed.[2] Electricity reserve margins for 2008 are approximately 22 percent for California under average summer weather conditions, slightly higher than in 2007. Even under hotter than average conditions, the reserve margins are approximately 14 percent.

Table 1: California 2008 Summer Outlook (MW)

Resource Adequacy Planning Conventions	June	July	August	September
1 Existing Generation	58,553	58,757	58,841	59,224
2 Retirements (Known)	0	0	0	0
3 High Probability CA Additions	204	84	383	0
4 Net Interchange *	13,118	13,118	13,118	13,118
5 Total Net Generation (MW)	71,875	71,875	71,959	72,342
6a 1-in-2 Summer Temperature Demand	60,751	60,844	61,094	61,439
6b 1-in-10 Summer Temperature Demand	64,819	64,918	65,185	65,553
7 Demand Response (DR)	644	644	644	644
8 Interruptible/Curtailable Programs	1,842	1,842	1,842	1,842
9a Reserve Margin (1-in-2 Demand)	**22.4%**	**22.2%**	**21.9%**	**21.8%**
9b Reserve Margin (1-in-10 Demand)	**14.7%**	**14.5%**	**14.2%**	**14.1%**

* Net interchange equals imports into California.

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[1] The report does not include an evaluation of the condition of the electricity market, specific contractual details, the adequacy of any individual utility or local distribution systems.

[2] A planning reserve margin defines the minimum level of electricity supplies needed to cover a range of unexpected contingencies, such as increased air conditioning demand on a hitter than-average day or an unplanned maintenance at a power plant.

A second measure of system adequacy is expressed as an operating reserve.[3] Dropping below this level triggers additional purchases of power and calls for demand response and voluntary interruptible programs to reduce load. The California Independent System Operator (California ISO) calls warning stages at 7 percent (Stage 1) and 5 percent (Stage 2). Stage 3 is called when reserves fall to a level between 3 and 1.5 percent, depending on the specific operating conditions.

The southern portion of the California ISO (SP26), covering most of Southern California, has a 3.8 percent probability of experiencing a staged emergency this summer, but still remains well below target reliability standards.[4] The California ISO Control Area and its northern sub-region (NP26) both have a probability of rotating outages of less than 1.5 percent. A probability cannot be expressed for the state total because the statewide system is composed of multiple control areas and does not operate as a single system.

Figure 1: Loss of Load Probability
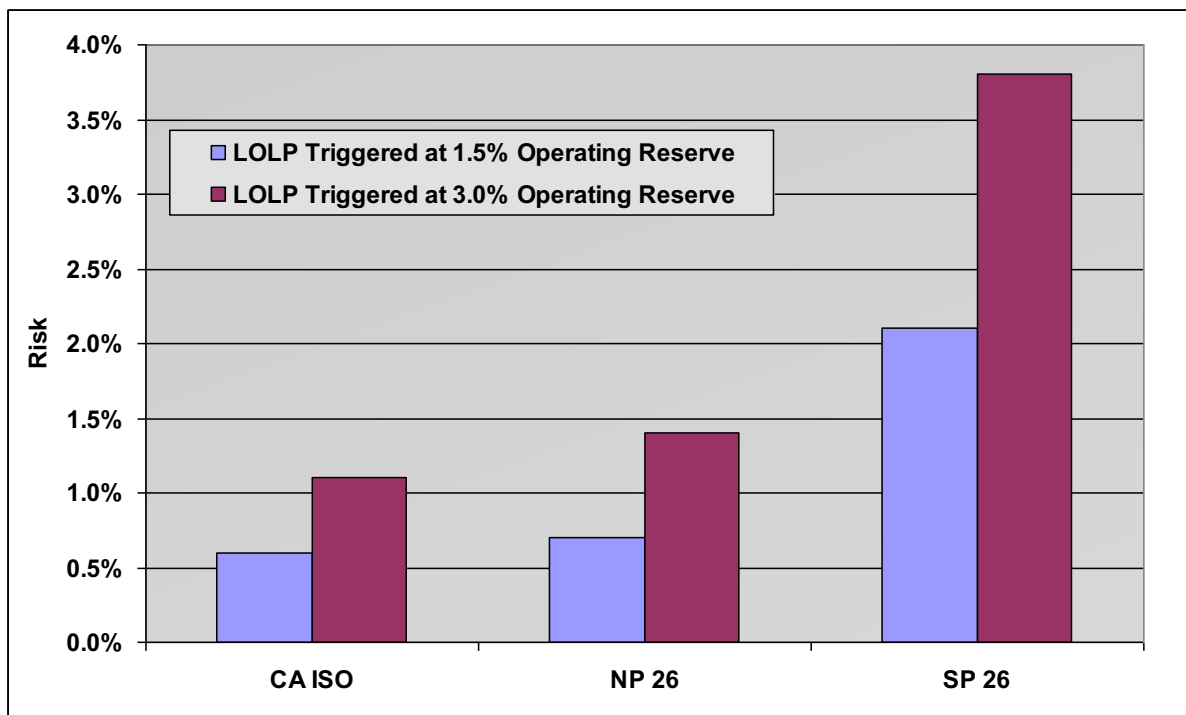
This assessment covers electricity generation and the large interconnected transmission system, but does not include possible failures within local distribution systems.

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[3] Operating reserve is the amount of imports and actual, spinning generation above current demand and represents real-time operations that fluctuate minute by minute.

[4] Current reliability standards are based on the expectation that a loss of load (demand) would occur no more frequently than one day in ten years. This standard is called a Loss of Load Probability.

This analysis was prepared in coordination and consultation with the California Public Utilities Commission (CPUC), the California ISO, utilities and other stakeholders. The Energy Commission also held a workshop on January 16, 2008 to receive stakeholder and public comments on the staff preliminary summer 2008 supply and demand outlook assessment.

2008 Summer Supply and Demand Outlook

This outlook examines four regions - California Statewide, California ISO Control Area, California ISO North of Path 26 (NP 26), and California ISO South of Path 26 (SP 26). The California Statewide includes the major investor-owned and municipal utilities in the state. The California ISO Control Area is divided into Northern and Southern California because there are transmission constraints south of the transmission segment known as Path 26, which limit the transfer of electricity from north to south. Northern California includes the Pacific Gas and Electric (PG&E) service area, participating municipal utilities and Energy Service Providers (ESPs) in Northern California served by the California ISO. Southern California includes Southern California Edison (SCE), San Diego Gas and Electric (SDG&E), Southern California municipal utilities and ESPs that participate in the California ISO. The *2008 Outlook* is based on forecasted loads in each region from the *California Energy Demand* 2008 – *2018 Staff Revised Forecast* published in November 2007.

The *2008 Outlook* summarizes a deterministic assessment (a single point forecast) of electricity imports and in-state generation reserves under average and hotter than normal summer conditions. The *2008 Outlook* also includes a probabilistic assessment (ranges of possible outcomes) to evaluate the cumulative risks of generation and transmission outages under variant peak demand levels. This assessment evaluates the likelihood that California may experience low operating (real-time) reserve margins and involuntary outages.

This assessment does not include any major changes in methodology to the tables that the staff completed for the *Summer 2007 Electricity Supply and Demand Outlook*. The most significant formatting change to the *2008 Outlook* is including the range of Loss of Load Probabilities (LOLP) for both 1.5 and 3 percent operating reserve margins. The *2008 Outlook* provides probabilistic studies for the entire California ISO Control Area, the NP 26 portion of the California ISO Control Area, and the SP 26 portion of the California ISO Control Area. The California Statewide outlook is only presented in a deterministic format because the statewide system is composed of multiple control areas and does not operate as a single entity.

Appendix A provides a detailed documentation of the assumptions used to develop the summer outlook and explanation of electricity supply adequacy criteria.

Tables 1 through **4** provide the estimated reserve margins for each of the four regions applying average summer demand projections (1-in-2) and hotter, more adverse weather conditions (1-in-10). The average reserve margin estimates for all regions exceed the 15 to 17 percent resource adequacy requirements for summer 2008. The California and SP 26

reserve margins will drop slightly below the target planning reserve margins, but are still sufficient to cover a range of other system contingencies (for example, unplanned facility outages).

Table 1: California 2008 Summer Outlook (MW)

Resource Adequacy Planning Conventions	June	July	August	September
1 Existing Generation	58,553	58,757	58,841	59,224
2 Retirements (Known)	0	0	0	0
3 High Probability CA Additions	204	84	383	0
4 Net Interchange *	13,118	13,118	13,118	13,118
5 Total Net Generation (MW)	71,875	71,875	71,959	72,342
6a 1-in-2 Summer Temperature Demand	60,751	60,844	61,094	61,439
6b 1-in-10 Summer Temperature Demand	64,819	64,918	65,185	65,553
7 Demand Response (DR)	644	644	644	644
8 Interruptible/Curtailable Programs	1,842	1,842	1,842	1,842
9a Reserve Margin (1-in-2 Demand)	**22.4%**	**22.2%**	**21.9%**	**21.8%**
9b Reserve Margin (1-in-10 Demand)	**14.7%**	**14.5%**	**14.2%**	**14.1%**

* Net interchange equals imports into California.

Table 2: California ISO 2008 Summer Outlook (MW)

Resource Adequacy Planning Conventions	June	July	August	September
1 Existing Generation	47,316	47,442	47,526	47,909
2 Retirements (Known)	0	0	0	0
3 High Probability CA Additions	126	84	383	0
4 Net Interchange *	10,350	10,350	10,350	10,350
5 Total Net Generation (MW)	57,792	57,792	57,876	58,259
6a 1-in-2 Summer Temperature Demand	46,895	48,918	49,071	48,633
6b 1-in-10 Summer Temperature Demand	49,745	51,891	52,053	51,588
7 Demand Response (DR)	644	644	644	644
8 Interruptible/Curtailable Programs	1,642	1,642	1,642	1,642
9a Reserve Margin (1-in-2 Demand)	28.1%	22.8%	22.6%	24.5%
9b Reserve Margin (1-in-10 Demand)	20.8%	15.8%	15.6%	17.4%

* Net interchange equals imports into the region.

Table 3: NP 26 California ISO 2008 Summer Outlook (MW)

Resource Adequacy Planning Conventions	June	July	August	September
1 Existing Generation	25,039	25,039	25,039	25,039
2 Retirements (Known)	0	0	0	0
3 High Probability CA Additions	0	0	0	0
4 Net Interchange *	250	250	250	250
5 Total Net Generation (MW)	25,289	25,289	25,289	25,289
6a 1-in-2 Summer Temperature Demand	21,214	21,671	21,380	20,597
6b 1-in-10 Summer Temperature Demand	21,538	22,467	22,165	21,354
7 Demand Response (DR)	458	458	458	458
8 Interruptible/Curtailable Programs	427	427	427	427
9a Reserve Margin (1-in-2 Demand)	23.4%	20.8%	22.4%	27.1%
9b Reserve Margin (1-in-10 Demand)	21.5%	16.5%	18.1%	22.6%

* Net interchange equals imports into the region.

Table 4: SP 26 California ISO 2008 Summer Outlook (MW)

Resource Adequacy Planning Conventions	June	July	August	September
1 Existing Generation	22,277	22,403	22,487	22,870
2 Retirements (Known)	0	0	0	0
3 High Probability CA Additions	126	84	383	0
4 Net Interchange *	10,100	10,100	10,100	10,100
5 Total Net Generation (MW)	32,503	32,503	32,587	32,970
6a 1-in-2 Summer Temperature Demand	26,254	27,835	28,276	28,604
6b 1-in-10 Summer Temperature Demand	28,328	30,034	30,510	30,864
7 Demand Response (DR)	186	186	186	186
8 Interruptible/Curtailable Programs	1,215	1,215	1,215	1,215
9a Reserve Margin (1-in-2 Demand)	29.1%	21.8%	20.2%	20.2%
9b Reserve Margin (1-in-10 Demand)	19.7%	12.9%	11.4%	11.4%

* Net interchange equals imports into the region.

The net interchange assumption represents a conservative estimate of potential electricity imports into each region, based on the western system capability to provide surplus generation during peak demand periods. This interconnected, inter-dependent wholesale power market provides reliability benefits and broad cost savings opportunities because the Pacific Northwest and the Desert Southwest each has a diverse mix of surplus electricity resources and different load patterns and can also sell electricity to California during the summer season. More details on this interconnected, inter-dependent wholesale power

market are found in Appendix A along with an assessment of hydroelectric dependable capacity and energy for summer 2008.

Table 5 provides a listing of the dependable capacity of all additions and retirements included in the *2008 Outlook*. The 765 megawatt (MW) Inland Empire Energy Center located in the SP 26 region has been derated (lower expected available capacity) by 50 percent as it will still be in an initial operational test and evaluation phase of construction. Inland Empire is the first GE H-System power plant to be constructed in the United States and the first 60 Hertz H-System in the world. For this reason, the Energy Commission agreed with Southern California Edison during the January 2008 workshop recommending a more conservative capacity estimate.

Table 5: 2008 Additions and Retirements

CA ISO Control Area					
SP26			**NP26**		
Additions			**Additions**		
Name	**MW**	**Expected**	**Name**	**MW**	**Expected**
Inland Empire (Derated)	383	Aug-08			
SCE Oxnard	44	Jun-08			
J Power Pala	82	Jun-08			
Wellhead Margarita	44	Jul-08			
Palomar Retrofit	40	Jul-08			
	593				
Non-CA ISO Control Areas					
LADWP & IID Control Areas			**SMUD & TID Control Areas**		
Additions			**Additions**		
Name	**MW**	**Expected**	**Name**	**MW**	**Expected**
Niland Peaker	78	Jun-08			

Figure 1 displays the staff estimate of the probability of involuntary load curtailment within the California ISO Control Area and the two sub-regions on a peak day for the summer 2008 period. To maintain the Western Electricity Coordinating Council (WECC) Minimum Operating Reserve Criteria, the California ISO continuously recalculates the operating reserve margin and will declare a Stage 3 Emergency when reserves fall to a level between 1.5 and 3 percent, depending on the current system operating conditions. The California ISO will initiate rotating customer curtailments under a Stage 3 Emergency to insure that the system remains stable and avoid the possibility of uncontrolled outages that can cascade throughout the west.

The Loss of Load Probability (LOLP) for both operating reserve margins is included in **Figure 1**. The actual LOLP would likely fall within the range between the two points provided. The SP 26 region has the highest probability of involuntary load curtailment or rotating outages. The corresponding LOLP for the region is between 2.1 and 3.8 percent, which is significantly lower than the acceptable planning criteria of one loss of load event every 10 years. The staff estimates that the California ISO Control Area and NP 26 both have an LOLP of less than 1.5 percent for summer 2008.

Figure 1: Loss of Load Probability
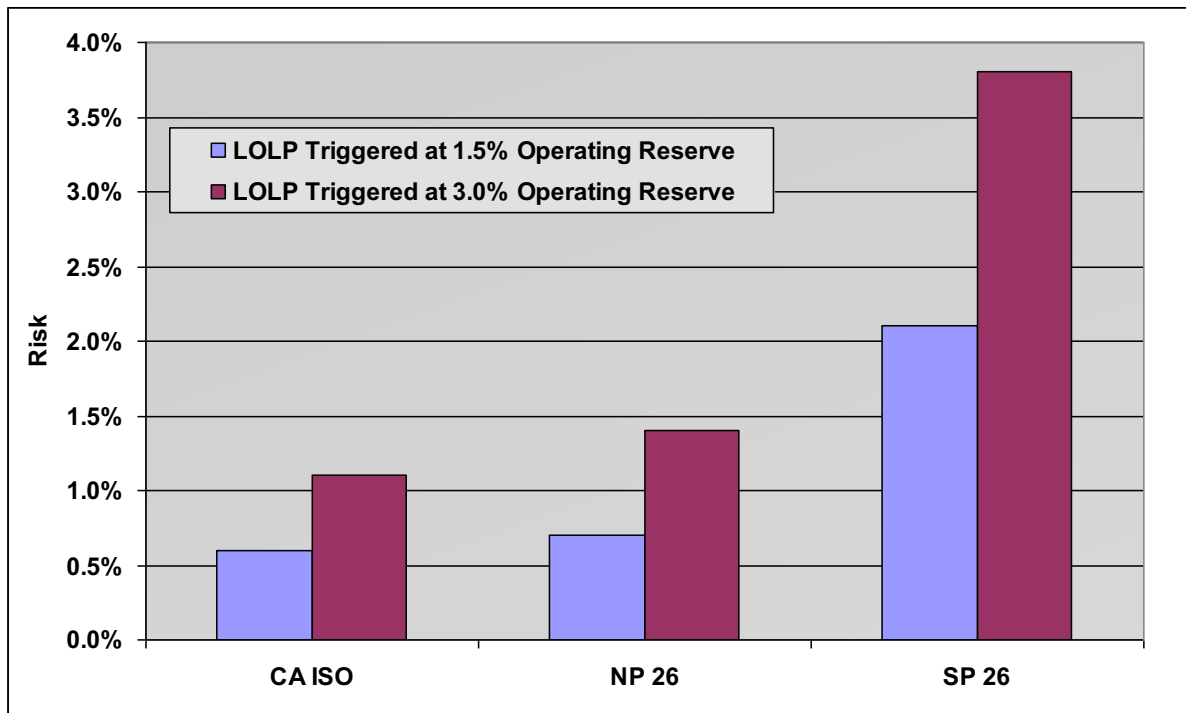
Utilities not under the California ISO Control Area have adequate resources to meet expected electricity demand this summer. These public utilities include Los Angeles Department of Water and Power (LADWP), Burbank Water and Power, Glendale Water and Power, and Imperial Irrigation District in Southern California and Sacramento Municipal Utility District (SMUD), Modesto Irrigation, Redding, Roseville Electric, and Turlock Irrigation in Northern California.

Regional Probabilistic Assessments

Planning reserve margins are a long-term measurement intended to assure sufficient electricity supplies can meet real-time operating reserve requirements and avoid a 1-in-10

year loss of load probability. The deterministic reserve margin calculations are suitable to evaluate whether each region within California falls within the planning reserve margin targets. This type of assessment, however, does not consider the variability or probability of different system fluctuations occurring. Many generators may simultaneously fail and cause a drop in operating reserves, but the deterministic assessment will not give an indication of the cumulative likelihood of this or other system emergency events. A statistical assessment of different system variables is necessary to evaluate the risks for dropping to lower operating reserve levels. The probability assessment provides a more rigorous evaluation of the system risks compared to deterministic calculations of operating reserves.

The staff continues to develop a full probabilistic assessment of the electricity system to enhance the deterministic tables provided in previous reports. The deterministic tables presented in previous outlooks included estimated reserve margins for two operating scenarios: expected (1-in-2) and adverse (1-in-10) conditions. In system planning, however, neither supply nor demand can be predicted with absolute accuracy or determined on a single point forecast. Future conditions that determine load, as well as availability of supply, can be better predicted within a range of uncertainty. Studies based just on the most likely set of conditions fall short of looking at the full range of possible demand levels and the fluctuation in supply capabilities. Likewise, studies based on adverse conditions are still limited in scope and may overestimate the exposed risk to these events.

As the summer 2006 showed, the peak load in Northern California was significantly higher than projected in the hotter than normal 1-in-10 forecast and was not captured by the deterministic methodology. This experience demonstrated that the single- or two-point deterministic evaluations are not sufficient. Therefore, a wider range of factors and future conditions should be evaluated to cover unexpected contingencies in the forecast of supply adequacy.

The observed performance of the electricity system over time and an extensive record of temperature conditions that are correlated to actual demand have allowed the Energy Commission staff to develop probability of occurrence measures for each of the major uncertainty factors. Incorporating the probability of occurrence to an electricity supply assessment provides a better representation of the fluctuations in the system and measures the risks of actually encountering an electricity emergency event based on historical data.

The Supply Adequacy Model (SAM) is a forecasting tool that assesses the balance of power supply and demand for a power system throughout the WECC regions. SAM was originally developed at the Energy Commission in 1998. For this analysis, the staff needed to modify SAM to analyze a specific region. This modified version of the SAM is referred to as SAM-A. The SAM-A was designed to be a relatively fast and simple analytical tool with the capability of incorporating uncertainty variables. The probabilistic approach for analyzing supply adequacy is an important feature of SAM-A, which differs from other deterministic models.

In the initial probabilistic study, the staff included the probabilities of high demand and generation forced outages in the Southern California (SP 26) portion of the California ISO Control Area. The SP 26 region was selected because it had the lowest planning reserve margin and presented the highest probability of not meeting operating reserve requirements. *The Summer 2006 Electricity Supply and Demand Outlook* incorporated the probability of forced outages of transmission lines in the SP 26 region. In the 2007 report, the staff added analysis of the entire California ISO Control Area and the NP 26 sub-region using the same three probabilistic variables of demand, generation outages and transmission outages.

There are a number of variables to consider when assessing supply adequacy of a system. This probabilistic assessment evaluates the complete range of demand scenarios based on weather variation, as well as generation and transmission outage occurrences based on historical data. The staff developed multiple cases of different resource availability, transmission capabilities and demand-varying scenarios using the Monte Carlo method to determine physical supply adequacy. **Figure 2** shows the major factors used to develop the 2008 outlook. The probabilistic methodology was applied to the factors in the highlighted boxes in the chart.

The staff is continuing to expand the probabilistic methodology and will continue to randomize the effects of additional factors when more information is made available from stakeholders. The following description is an explanation of how the probabilistic methodology was applied to analyze the SP 26 region. The analytical process is the same for all three regions, but SP 26 was selected for illustrative purpose because it has the highest risk of firm load curtailments.

Probability of Demand

The probability of demand calculations are based on the most recent adopted Energy Commission demand forecast.[5] Peak electricity demand does not always occur in the hottest day of the year. There is a strong correlation between peak electricity demand and a buildup of high temperatures over several days. To incorporate the effect this buildup of heat has on peak demand, the staff calculated a weighted average temperature (max 631). The weighting consists of 60 percent of the current day's maximum temperature, 30 percent of the previous day's maximum and 10 percent of the second previous day's maximum. The lag is used to account for heat build-up over a three day period.

The staff used the "max 631" to develop a temperature response adjustment for varying degrees of hotter-than-average temperatures. The staff estimated the relationship between

temperature and daily peaks using recorded 2004 hourly loads reported to FERC by SCE and SDG&E, and a three-day moving average of daily maximum temperatures weighted by the number of air conditioning units estimated to be in each region. The estimation included weekdays from June 15 through September 15, on which the weighted average maximum temperature was above 75 degrees in SCE, or 70 degrees in SDG&E service territories.

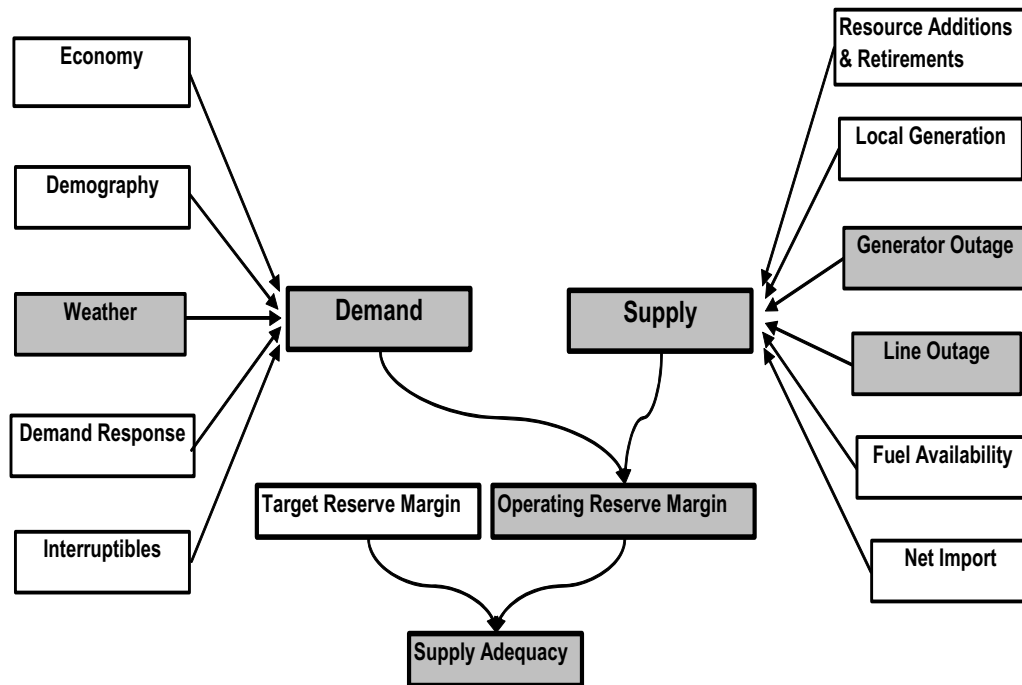**Figure 2: Major Factors Affecting Supply Adequacy**

Figure 3 and **Figure 4** illustrate the relationship between 2004 temperatures and loads, plus the estimated weather response function for SCE and SDG&E respectively. By calculating the slope, the staff determined that a one degree increase in weighted average temperature equates to a 317 MW increase in peak demand for SCE and a 66.5 MW increase for SDG&E.

The staff then compared the weighted average temperature for the 55 years of historic weather data to calculate a distribution of summer 2008 peak demand possibilities. For example, if the weighted average temperature used in the demand forecast for SP 26 is 98 degrees and the weighted average temperature in 1976 was 101, the resulting 2007 peak demand increase using 1976 temperature data would be 1,150 MW ((317+66.5) * (101-98)) for the SP 26 region. Finally, the staff applied the change in demand for each recorded peak temperature over the 55 year period to develop a peak demand distribution. The resulting probabilistic graph for Southern California is presented in **Figure 5**. The chart characterizes the probability of aggregated load occurring for the whole Southern California region.

Figure 5 shows that the range of SP 26 demand in 2008 could be as low as 25,650 MW or as high as 31,580 with a 'most likely' demand of 28,600 MW. While the forecast could equally be higher or lower than the mean, the risks associated with the higher options are more relevant for planning considerations.
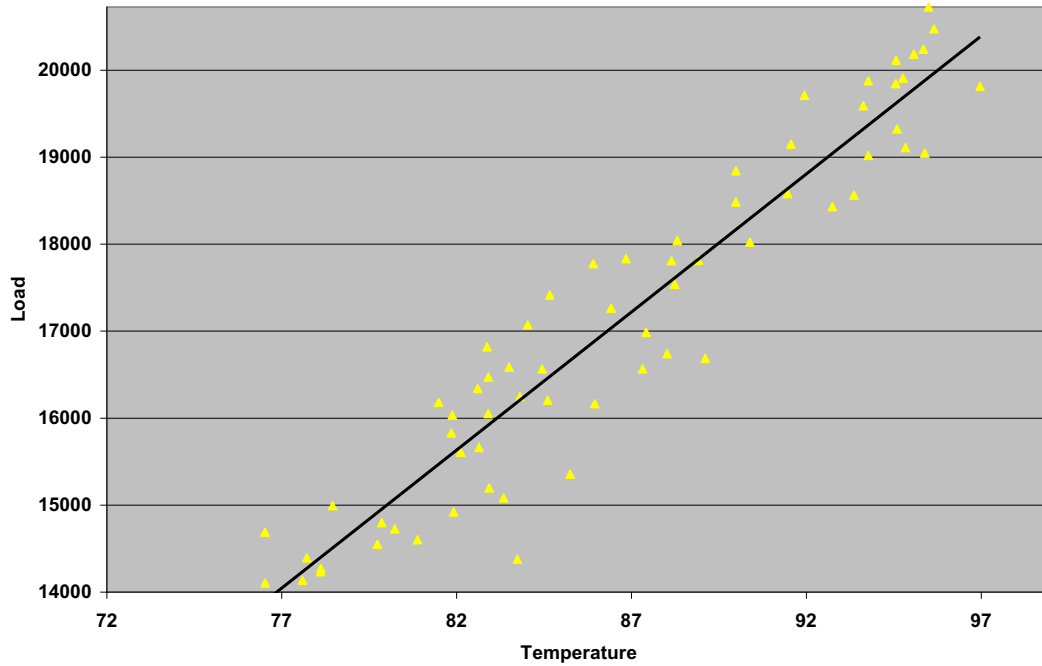
Figure 3: SCE Load vs. Temperature Relations

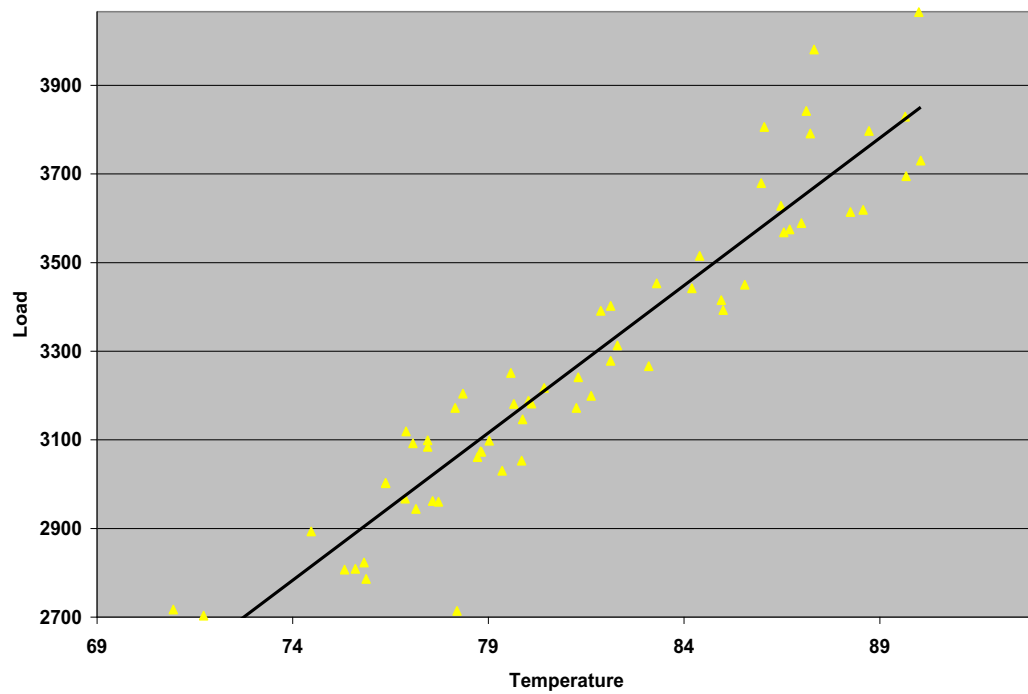**Figure 4: SDG&E Load vs. Temperature Relations**

Figure 5: Probability of Demand California ISO SP 26 Summer 2008
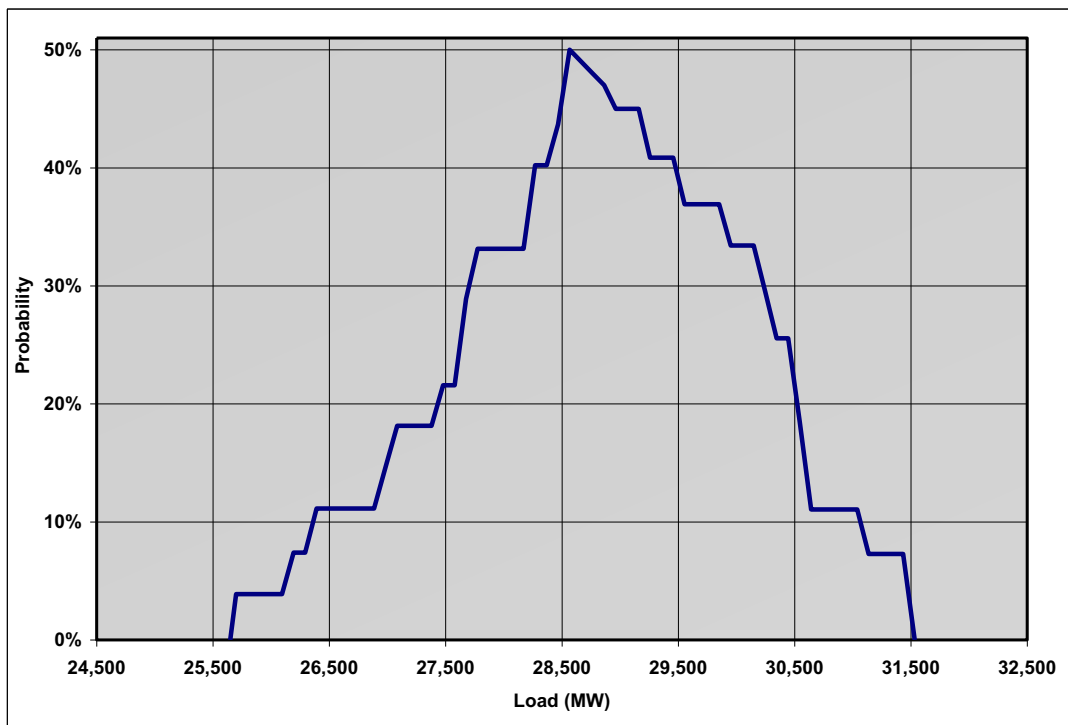
Probability of Generation Forced Outages

Similar to the impact and range of possible demand, the magnitude of the total available resources can be expected to fall within a range of uncertainty due to the variation in forced outages. The Energy Commission staff calculated potential 2008 outages using actual 2002 thru 2007 daily outage totals for the summer peak period provided by the California ISO. This set of data was statistically processed, and the results are presented in **Figure 6**.

Figure 6 shows the range of SP 26 forced outages in 2008 could be as low as 190 MW or as high as 2,990 MW, with a 'most likely' outage number of 1,075 MW. Again, the risks associated with the higher outages are the more relevant factors for resource planning considerations. The staff estimates a 10 percent probability that forced outages will be as high as 1,915 MW, and a three percent probability that they will be as high as 2,450 MW.

Figure 6: Probability of Generation Forced Outages California ISO SP 26 Summer 2008
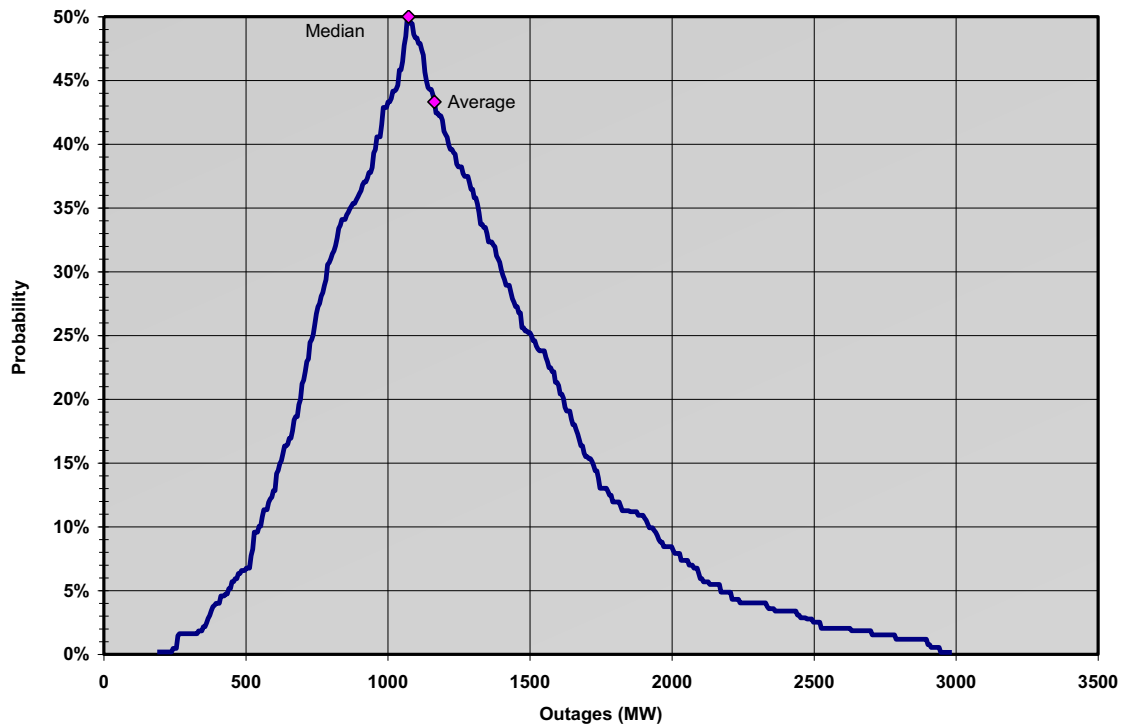
Probability of Transmission Line Forced Outages

A major transmission line outage can also have significant impacts on the overall operation of the system. These outages often occur with little or no warning and, in the case of the

Pacific DC Intertie (PDCI), can account for as much as a 2,000 MW reduction in resources available to meet load. On August 25, 2005, the PDCI unexpectedly dropped out of service just as Southern California was approaching its daily peak load. This outage, coupled with a 2,000 MW deviation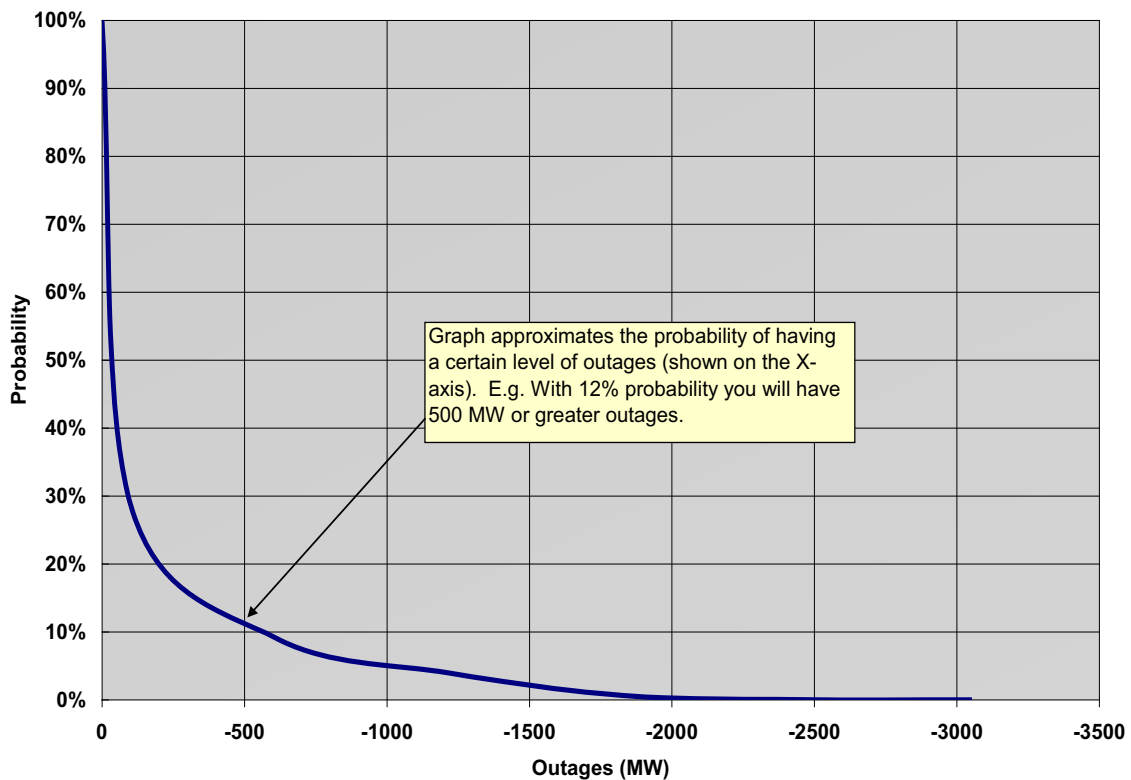 in the day-ahead peak demand forecast, required the California ISO to issue a Transmission Emergency notice requesting utilities in SP 26 reduce demand by curtailing 900 MW of firm load and 800 MW of voluntary interruptible load for about 35 minutes.

The staff included the effects of major transmission outages in the probabilistic analysis for this report. To calculate the overall impact of these failures on the SP 26 region, the staff used data obtained by subpoena from the California ISO to compare hourly transfer capacities with the WECC rating for each transmission line. One limitation of using this methodology is that it may omit short duration outages that are not visible at the time the transfer capacity is reported. For example, a line that trips off at five minutes after the hour and is restored 50 minutes later would not be visible in the dataset. **Figure 7** provides the range of transmission outages observed from May 15 thru September 15 for the years 2003 thru 2006.

Figure 7: Probability of Transmission Line Forced Outages California ISO SP 26 Summer 2008

Graph approximates the probability of having a certain level of outages (shown on the X-axis). E.g. With 12% probability you will have 500 MW or greater outages.

Probability of Maintaining Minimum Required Operating Reserves

Calculating generation and transmission availability and comparing the sum against a complete range of electricity demand results in a probabilistic assessment of resource adequacy. Using the Monte Carlo method, 5,000 cases of different resource and demand scenarios are developed for summer 2008. Each case is then reviewed to determine whether resources are sufficient to meet demand plus minimum operating reserves. The SAM-A model conducts the calculations in the following four major steps:

1. Using Monte Carlo draws, the model generates a deterministic case of input data in which each uncertainty factor takes a random value from its respective range of possible values.

2. Evaluation of the adequacy of supply is made for each deterministic case using spreadsheet tables.

3. The above steps are repeated for multiple cases to reasonably cover all possible combinations of the values of the uncertain factors.

4. The resulting set of cases is statistically processed to calculate:

    a. The probability that there is <u>insufficient</u> capacity to meet the peak demand and maintain a given reserve margin.

    b. The probability that there is <u>sufficient </u>capacity to meet the peak demand and maintain a given reserve margin.

Figures 8 thru **10** provide the probabilities for dropping to the minimum operating reserve margin levels for each of the three studied regions.

Figure 8: Operating Reserve - California ISO Summer 2008
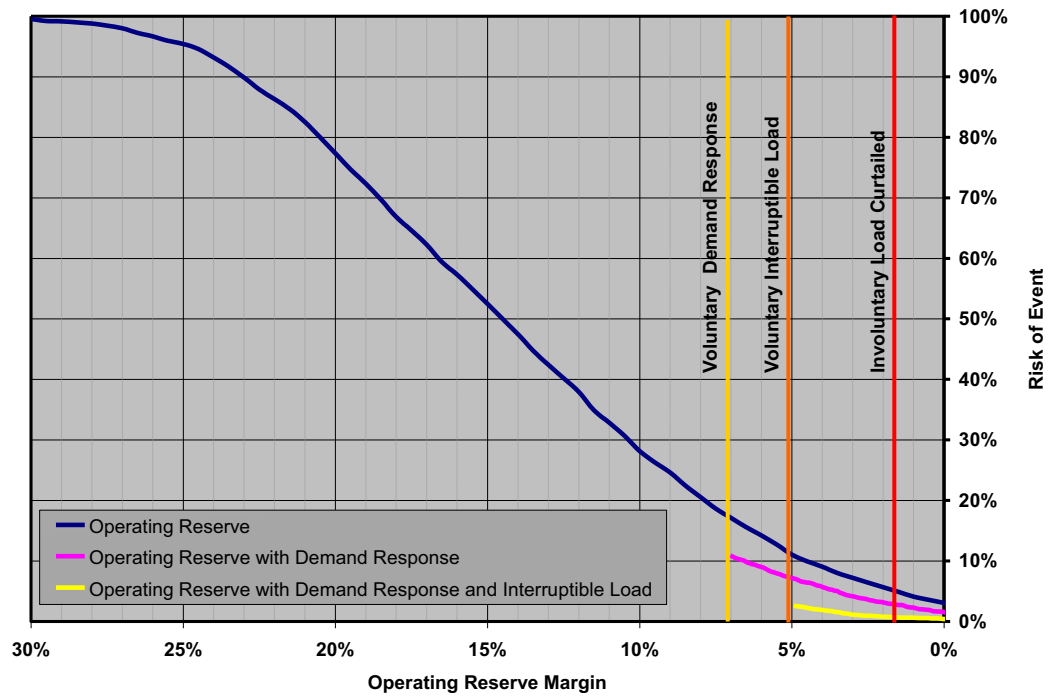
Figure 9: Operating Reserve - California ISO NP 26 Summer 2008

Figure 10: Operating Reserve - California ISO SP 26 Summer 2008
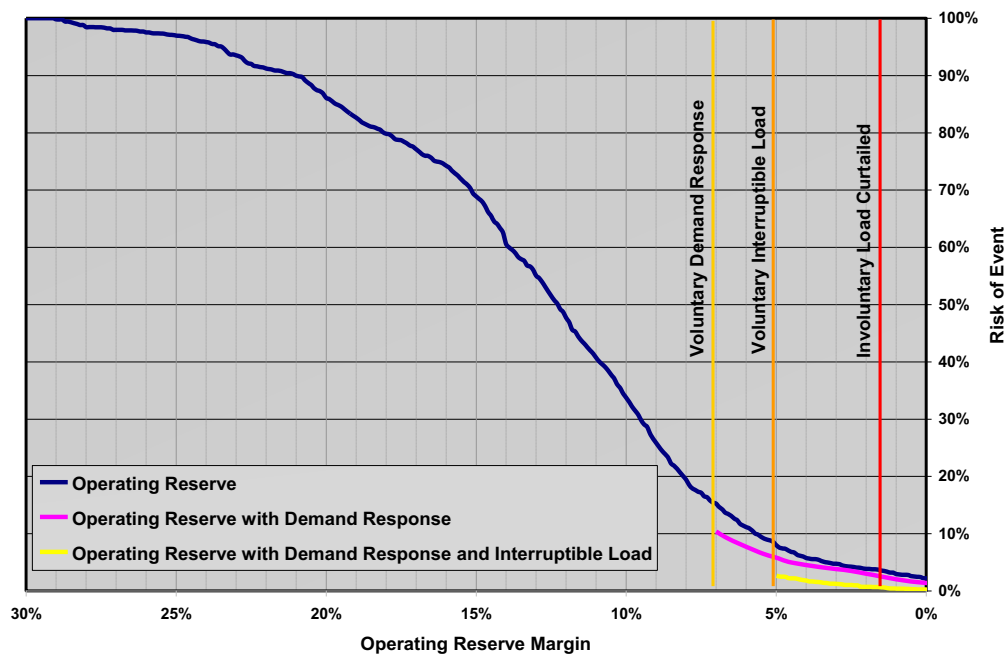
Figure 10: Operating Reserve - California ISO SP 26 Summer 2008
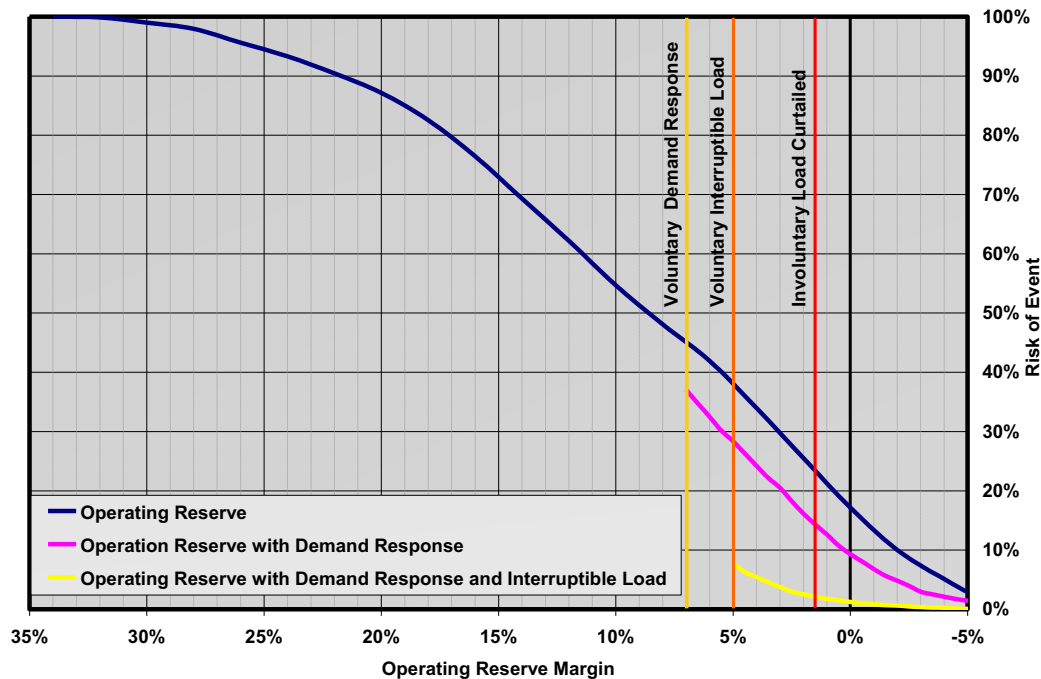
Figure 11 provides a snapshot of the critical points identified in **Figures 8** thru **10** for each of the three regions on the peak day of summer 2008. The results can be also interpreted in terms of risk. The staff assessment shows that there is a very low risk of involuntary load curtailments (Stage 3 Emergency at 1.5 percent operating reserves) in the California ISO and NP 26 regions. The staff completed risk calculations for operating reserve margins dropping to 3 percent (high end of Stage 3 Emergency alert) and found the California ISO, NP 26 and SP 26 probability of events increased to 1.1 percent, 1.4 percent and 3.8 percent, respectively. The risk of curtailing firm load is higher in the SP 26 region, but still remains significantly lower than the target planning criteria for a one event every 10 years, or a 10 percent probability.

The likelihood of utilizing voluntary demand response and interruptible load programs is much higher in SP 26. This may be considered an acceptable risk level, however, since the customers enrolled in these programs receive preferential rates or other incentives to provide an extra level of mitigation during peak load conditions.

Figure 11: Risk of Event on the Summer 2008 Peak Day
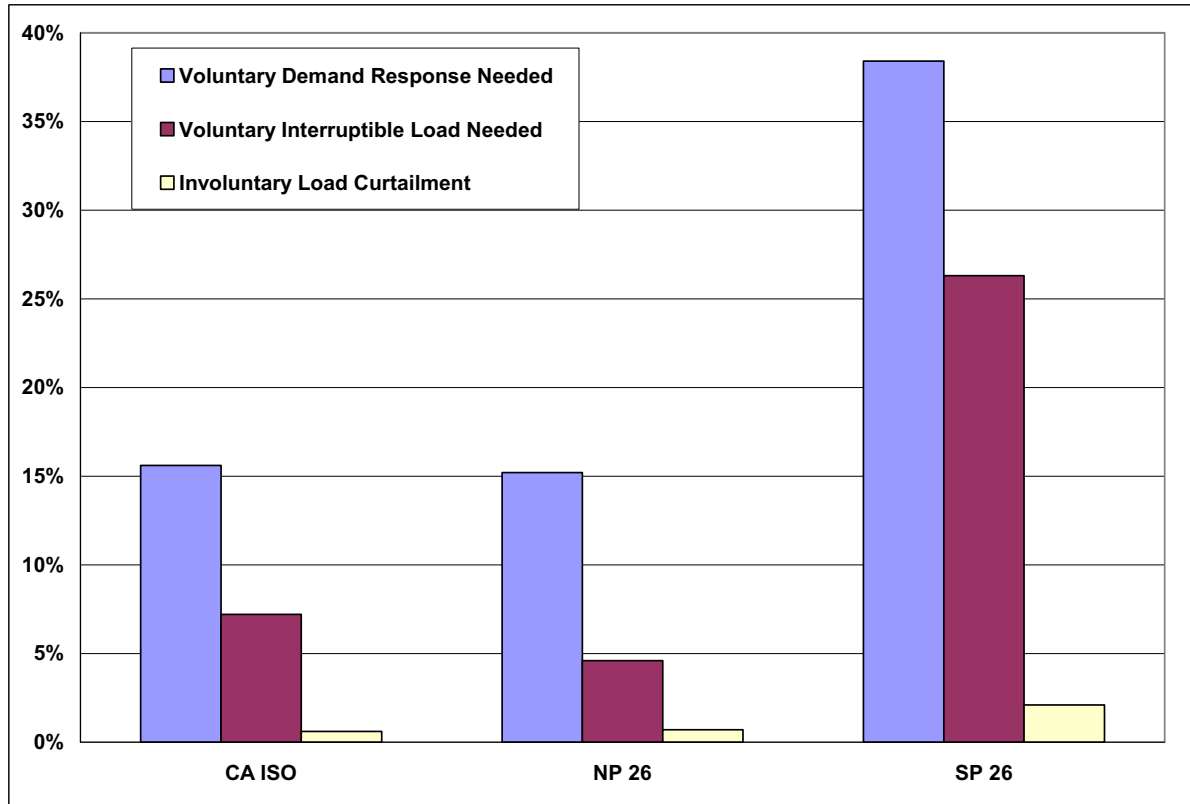
APPENDIX A: DETAILED ASSUMPTIONS USED TO CALCULATE PLANNING RESERVE MARGINS

Electricity Supply Adequacy Criteria

The Energy Commission studies potential long-term (10-20 years) electricity supply and demand conditions to ensure that California maintains a sustainable and reliable energy system into the future. The Energy Commission also analyzes short-term market developments and a range of potential system variations to determine if there are any significant risks of potential supply shortfalls during the upcoming peak demand season. This analytical activity became particularly important following the 2000-2001 energy crisis experiences.

The electricity supply assessment for the summer peak demand season includes evaluating existing reserves that serve as a buffer for unplanned fluctuations and analyzing the probabilities that a system emergency may occur. A **reserve margin** is a measure of the amount of electricity imports and in-state generation capacity available over average peak demand conditions. Reserve margins are measured at two levels: planning and operating.

A specified **planning reserve margin** target is the level necessary to cover a particular range of possible system fluctuations and unexpected emergencies. The planning reserve margin target is based on the possibility that a loss of load would occur no more frequently that one day in ten years. Rare conditions will occur, such as the 2006 summer temperatures that caused a simultaneous spike in electricity demand throughout California and the West. Even though this greater than 1-in-30 year event topped out above the range of uncertainties established for the planning reserve margin target, sufficient electricity imports and generation supplies avoided any customer curtailments.

A planning reserve margin that is too low may result in a higher chance of customer curtailments. A target reserve margin that is too high may dampen generation and transmission investment incentives, cost more than consumers are willing to pay for the risk of an outage, and frustrate new development (including renewables and demand response) that depends on evolving regulatory decisions. Increasing the planning reserve margin to cover a larger range of contingencies would require more generation and transmission facilities to be built which could stand idle until the rare event occurs. The goal is to balance the risks of outages and overall costs to maintaining a redundant system.

The one-day-in-ten-years criteria has been used as an acceptable risk for outages and translates into a 15 to 17 percent planning reserve target, which has been the reliability standard for years. The CPUC uses this target for determining the amount of electricity supplies that the investor-owned utilities must procure to meet customer demand.

An **operating reserve margin** is the amount of imports and actual ("spinning") generation above <u>current</u> demand, and represents real-time operations that fluctuate minute to minute.

The operating margin is the target buffer that is assumed to be sufficient for control area operators to deal with immediate emergencies or fluctuations in electricity demand, such as hotter than predicted day-ahead temperatures, and/or generation, such as unplanned maintenance. The regional North American Electric Reliability Councils (NERC) establish Minimum Operating Reserve Criteria (MORC) that is necessary to maintain system reliability. The Western Electricity Coordinating Council is the regional body that evaluates the MORC levels for all west coast system operators.

The minimum operating reserve criteria target is approximately 7 percent, but varies depending on the portfolio mix of generation resources. To be counted as part of the operating reserves, conventional generation facilities must be ready to generate electricity when needed. Hydro-generation systems only require a 5 percent operating reserve target since these facilities can generate electricity on a moments notice. Electricity imports are usually backed up by the operating reserves within the source region.

Detailed Description of Data and Assumptions

Tables A-1 thru **A-7** provide a more detailed description of the data and assumptions used to calculate the planning reserve margin in the *Summer 2008 Electricity Supply and Demand Outlook.*

Existing Generation

Existing generation accounts for thermal and hydro generation facilities operational as of August 1, 2007. Thermal generation consists of California ISO control area merchant and municipal thermal resources (including non-hydro renewable), Investor-Owned Utility (IOU) retained generation, and Qualifying Facilities (QFs). The merchant thermal generation in SP 26 includes 1,080 MW of contracted capacity from units located in Baja California Norte. Thermal unit capacity is derated to reflect summer operating conditions. The summer derate capacity can range from 90 to 96 percent of nameplate capacity based on the type of unit and location. The Non-California ISO generation totals include both thermal and hydro capacity. **Table A-1** provides a more detailed breakout of existing generation.

Table A-1: Derated Existing Generation

	SP26	NP26	TOTAL
CA ISO Control Area			
Merchant Thermal & QF	17,049	16,525	33,574
Municipal Thermal	751	182	933
IOU Retained Thermal	3,430	2,393	5,823
Derated Hydro	1,047	5,939	6,986
TOTAL CA ISO	**22,277**	**25,039**	**47,316**
Non-CA ISO	6,523	4,714	11,237
STATEWIDE TOTAL			**58,553**

Dependable hydro capacity at peak does not significantly change between a wet and a dry water year even though the historic record shows that dry conditions can have a significant impact on available energy production. The estimate of dependable hydro capacity that the staff uses is based on low water year conditions and would only be revised slightly upward in an extremely wet year to account for additional run-of-river capacity that could be produced in June and early July by additional runoff.

Hydroelectric Dependable Capacity and Energy for Summer 2008

California experienced the driest March-April combined since record-keeping began in 1921. Though the snow pack and forecast runoff are now well below average, hydroelectric capacity will still be available to meet peak power needs. Total hydroelectric energy production for 2008 will likely be 80 to 85 percent of average.

The forecast runoff for combined flows on the Sacramento, Feather, Yuba and American rivers are down to 59 percent of average (11 million acre-feet for April through July). Forecast runoff in the Stanislaus, Tuolumne, Merced, and San Joaquin river (into Millerton Lake) is just 62 percent of average (3.7 million acre-feet). The "water year type" for both the Sacramento and San Joaquin watersheds is now defined as "Critical" (the driest of 5 categories, the others being Wet, Above Average, Below Average, and Dry).

Hydroelectric electricity generation will be most affected when demand is off-peak and during shoulder hours. Generation from utility-owned power plants during peak-hour demand should not be significantly reduced, since water is conserved first and foremost for these periods when power is valued the most. Hydroelectric energy production during October will be down substantially this year compared to past years, as reservoirs throughout the state will be drawn down.

Forecast runoff at The Dalles on the Columbia River is expected to be 106 percent of average for the months of May through August 2008. That is the median forecast (83 million acre-feet) posted by the Northwest River Forecast Center on May 7, 2008. There is a 95 percent chance that runoff will be at 73 million acre-feet, and a five percent chance it will exceed 115 million acre-feet. The confidence in seeing above-average runoff comes in part from a heavy winter snow pack that was much colder than average. While snowfall and rainfall in California is often scant after mid-May, rainfall in the Pacific Northwest is often abundant in early summer months, which would add to the massive flows already expected in the Columbia Basin.

What this means for California is that the availability of electricity imports from the Pacific Northwest will be well above average this year. North-to-south power flows are likely to fill the AC and DC ties this year more often than average, since the cost of hydroelectric energy production is always less than alternative supplies from fossil fuel resources. Spot market prices will still be set by gas-fired generation on the economic margin for scheduling and dispatch. Based on higher marginal cost prices, northwest sellers of hydroelectric energy will have strong financial incentives to export energy to California this summer.

Precipitation in the Desert Southwest region has again been below average this year. Due to declining Lake Mead elevations, Hoover generating capacity will be reduced by 250 MW to 400 MW. When Lake Mead is full, Hoover generating capacity is equal to its nameplate capacity of 2,080 MW. California LSEs have contracted for 80.6 percent of the total of contracted capacity (1,945 MW). The April 2008 USBR forecast for Hoover capacity is 1,677 MW in June and July, then 1,689 MW in August, and 1,726 MW in September (when demand peaks most often in Southern California).

Additions and Retirements

Table A-2 provides a listing of the dependable capacity of all additions and retirements included in the *2008 Outlook*. The 765 MW Inland Empire Energy Center located in the SP 26 region has been derated by 50 percent as it will likely still be in an initial operational test and evaluation phase of construction. Inland Empire is the first GE H-System power plant to be constructed in the United States and the first 60 Hertz H-System in the world. For this reason, the staff agreed with SCE's comments during the January 2008 Workshop to use the more conservative capacity.

Table A-2: 2008 Additions and Retirements

CA ISO Control Area					
SP26			**NP26**		
Additions			**Additions**		
Name	**MW**	**Expected**	**Name**	**MW**	**Expected**
Inland Empire (Derated)	383	Aug-08			
SCE Oxnard	44	Jun-08			
J Power Pala	82	Jun-08			
Wellhead Margarita	44	Jul-08			
Palomar Retrofit	40	Jul-08			
	593				
Non-CA ISO Control Areas					
LADWP & IID Control Areas			**SMUD & TID Control Areas**		
Additions			**Additions**		
Name	**MW**	**Expected**	**Name**	**MW**	**Expected**
Niland Peaker	78	Jun-08			

Net Interchange

The net interchange assumption represents a conservative estimate of potential electricity imports into each region, based on the western system capability to provide surplus generation during peak demand periods. The interconnected, inter-dependent wholesale power market provides reliability benefits and broad opportunities for cost savings due to a diverse mix of surplus electricity resources and different load patterns in each region. Electricity is imported from other western states, Canada and Mexico for various reasons, involving different types of long-term and short-term transactions.

Electricity is imported from ownership shares of generating plants located in other states and owned by California utilities and long-term contracts. The amount of imports associated with these specified sources are relatively stable and do not vary from year-to-year. The rest of the electricity imports are generally short-term transactions that are traded on the Western wholesale power market, representing almost half to the total imports during the year. California utilities and generators purchase short-term market electricity to reduce costs, displacing the need to operate more expensive generation facilities in California. Short-term electricity purchases also occur to occasionally meet unexpected supply shortfalls due to higher-than-expected demand or facility outages. The California Independent System Operator will purchase short-term electricity if actual demand is higher than the day-ahead forecast and need to supplement the scheduled generation.

The amount of short-term imports may vary seasonally, usually depending on hydro-generation conditions in both California and the Pacific Northwest region. The amount of short-term imports may also vary day-by-day, depending on different market incentives or

if there are operating constraints. If the California ISO requires a generator to operate during high demand conditions, the generator does not have an opportunity to purchase lower cost electricity that is available on the western spot market and imports will likely decline. Ironically, imports may be low during high load periods because of this constraint and higher during average demand conditions. Yet, electricity imports were available and critical for maintaining system reliability during the unusual high demand conditions in 2006 that was greater than a 1-in-30 year event.

Energy Commission staff determined that there is a sufficient quantity of surplus capacity in neighboring regions to meet the net interchange estimates detailed below. **Figure A-1** provides a summary of the Bonneville Power Administration forecast of surplus capacity in the Northwest by various water conditions. Even in the driest year on record (1937), there is enough surplus capacity in the region to meet the interchange assumption included in the outlook.

The staff determined the amount of surplus resources in the Southwest by conducting internal modeling simulations and reviewing the *WECC Summary of Estimated Loads and Resources Report* issued in June 2006.

Figure A-1: 2008 Forecast of Northwest Regional Surplus/Deficit by Water Year
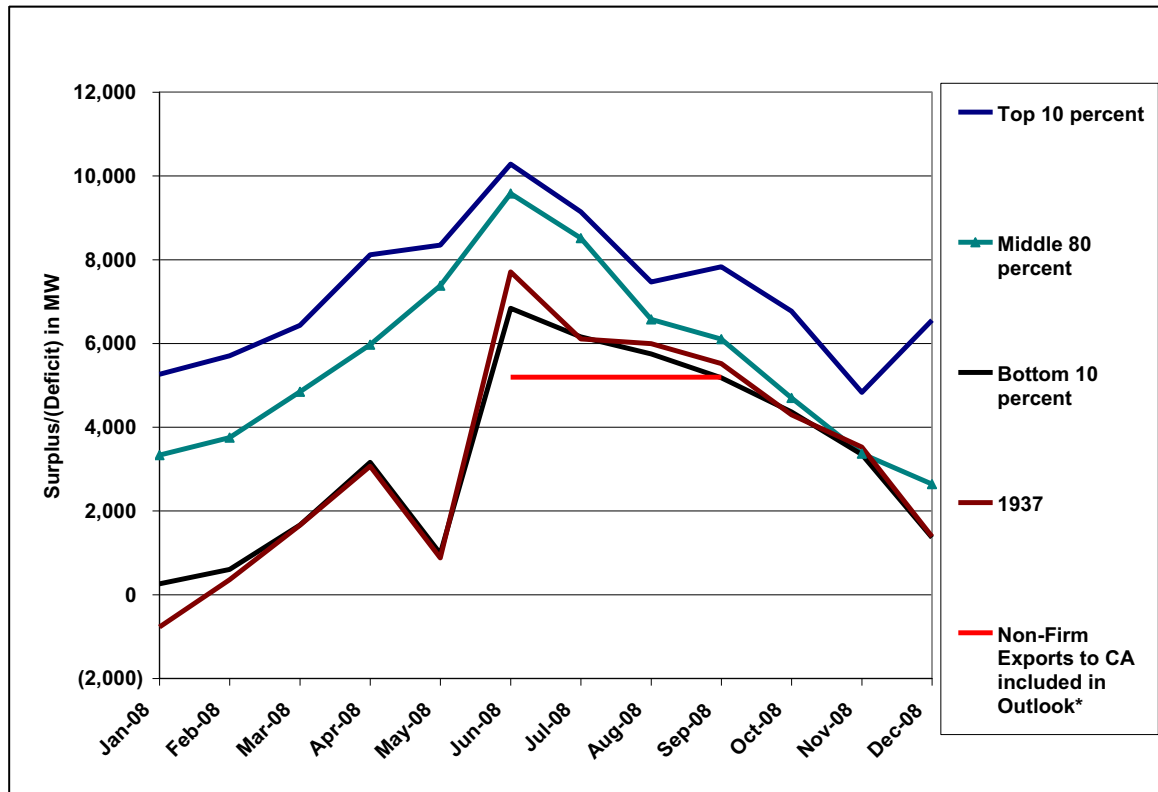
Based on 2006 BPA White Book 1-Hour Capacity in Megawatts

Tables **A-3** through **A-6** provides details on the individual components of net interchange for each of the four regions. Some imports are identified as capable of carrying their own reserves since transmission is the factor that limits capacity exchange, and there is sufficient surplus to replace a generation outage from the exporting region.

Table A-3: Statewide Net Interchange

Northwest Imports (COI)[6]	4,000
Southwest Imports[2]	4,100
Pacific DC Intertie (California ISO)[2]	2,000
LADWP and IID Control Areas	3,018
Total	**13,118**

Table A-4: California ISO Net Interchange

California ISO Share of NW Imports (COI)[2]	2,300
WAPA Central Valley Imports	950
Southwest Imports[2]	4,100
Pacific DC Intertie (California ISO) [2]	2,000
Net LADWP Control Area Interchange	1,000
Total	**10,350**

Table A-5: NP 26 Net Interchange

California ISO Share of NW Imports[2]	2,300
WAPA Central Valley Imports	950
Path 26 Exports	(3,000)
Total	**250**

Table A-6: SP 26 Net Interchange

Path 26	3,000
California ISO Share of Pacific DC Intertie[2]	2,000
Net SW Imports[2]	4,100
Net LADWP Control Area Interchange	1,000
Total	**10,100**

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[6] Imports assumed to carry reserves as transmission is the limiting factor.

The LADWP Control Area interchange values provided in **Tables A-4** and **A-6** include power that is wheeled through the LADWP Control Area to other municipal utilities served by the California ISO. **Tables A-5** and **A-6** include 3,000 MW of Path 26 North to South flows from NP 26 to SP 26. The export reflects the greater need of capacity in SP 26 than NP 26, but does not imply that it is contractually obligated to be delivered into SP 26. This is a topic that the staff has identified for additional analysis to improve the modeling of this assumption. **Figure A-2** provides the actual flows on Path 26 for the hour ending 1600 during summer 2006. Negative numbers indicate North-to-South flows and positive numbers are South-to-North. There is clearly a wide range of variation in the flows from one day to the next and, in the case of the heat storm period (July 24 and 25); the North-to-South flow was less than 1,000 MW during the unusual periods of extreme temperatures in Northern California.

Figure A-2: Path 26 Summer Flows HE 1600
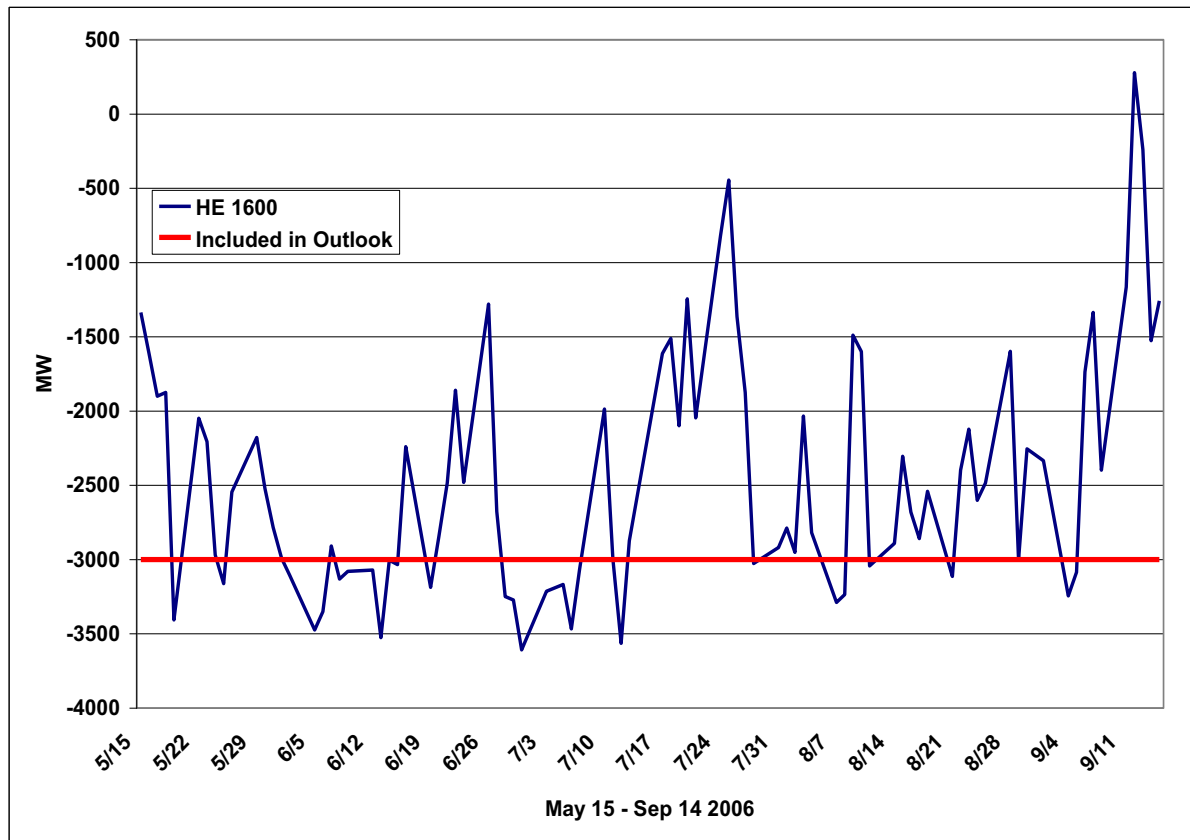
1-in-2 Summer Temperature Demand (Average)

The demand forecast for the *2008 Outlook* is the Statewide 1-in-2 Electric Peak Demand by Load Serving Entity (MW), Base Case in the latest adopted Energy Commission demand

forecast[7]. Complete documentation of assumptions and methodologies are included in the above reports.

Demand Response and Interruptible Programs

There are several mitigation measures available to the California ISO and individual utilities to respond to adverse conditions when operating reserves fall below minimum acceptable levels. **Table A-7** details the expected IOU demand response and interruptible programs that are established at the CPUC and/or have been contracted by an IOU. There is also an additional 110 MW of demand response from pumping load in SP 26 that is not included in the PUC filings but included in **Table A-7** as Special Contracts.

Table A-7: IOU 2008 Demand Response and Interruptible Load Programs

Demand Response Programs	Expected		
	SCE	SDG&E	PG&E
CPP Programs	3	15.0	48.0
DBP	34	6	55
CBP	75	23	27
CAL-DRP/Spec Contracts	10		308
CI 20/20 or BEC		20	20
Demand Response Sub-Total	**122**	**64**	**458**
Interrruptible Load Programs			
I-6 or E-19/E-20			
AL TOU CP			
BIP	476	5	288
ACCP	562	25	96
OBMC/RBRP	3		13
AP-I/Emergency CCP/NF	21	3	30
Clean Gen/Peak Gen		10	
Special Contracts	110		
Interruptible Sub-Total	**1172**	**43**	**427**
Total	**1294**	**107**	**885**

A detailed explanation of the demand response programs identified in **Table A-7** follows:

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[7] *California Energy Demand 2008-2018 - Staff Revised forecast*. Publication # CEC-200-2007-015-SF2. [http://www.energy.ca.gov/2007publications/CEC-200-2007-015/CEC-200-2007-015-SF2.PDF]

Demand Response Programs

CPP - Critical Peak Pricing: CPP rates offer discounts (energy, demand or both, depending on the particular design) in non-critical hours but charge a premium for energy consumed on a limited number of days when system conditions are forecast to be critical, typically due to high expected demand or supply shortfalls.

DBP—Demand Bidding Program: Participants are paid an incentive for load reductions during curtailment events that are "bid" in to the utility a day in advance. There is no penalty for not bidding or not fulfilling the bid obligation.

CAL-DRP—California Demand Reserves Partnership: Program aggregators provide a contracted amount of load reduction during curtailment events by aggregating participant load reductions. Aggregators are paid a monthly capacity reservation charge for contracted load reduction amounts and an additional energy payment for consumption avoided during curtailment events.

C/I 20/20—20/20 for Commercial/Industrial customers (SDG&E only): A 20 percent bill credit given to customers who reduce on-peak consumption by an average of 20 percent or greater over all critical peak days.

BEC—Business Energy Coalition: A pilot program in the PG&E service territory operated in partnership with The Energy Coalition, participants are paid a per kW incentive to reduce load during curtailment events. The Energy Coalition works with participating customers to develop customized load reduction strategies.

Interruptible Load Programs

I-6— SCE Traditional non-firm rate: provides discounted energy and demand charges for load subject to curtailment during Stage 2 or 3 system emergencies. Per-kWh non-compliance penalties are applied to consumption above the contracted firm service level during events.

E-19/E-20—PG&E traditional non-firm rates: provide discounted energy and demand charges for load subject to curtailment during Stage 2 or 3 system emergencies. Per-kWh non-compliance penalties are applied to consumption above the contracted firm service level during events.

AL TOU CP—SDG&E critical peak rate: On-peak energy charges increase to $1.80/kWh during "critical peak" events, defined as Stage 2 or 3 system conditions.

BIP—Base Interruptible Program: Relatively new interruptible program that offers demand charge credits for load subject to interruption during system emergencies. Significant per kWh penalties apply for non-compliance.

ACCP—Air Conditioner Cycling Program (SCE only): Residential and small - to medium-sized commercial and industrial customers receive a bill incentive to allow SCE to remotely

cycle their AC during system emergencies or high demand periods. The incentive varies based on the percent time the customer is willing to have his equipment cycled off.

OBMC—Optional Binding Mandatory Curtailment: Offers blackout avoidance during rotation outages for up to a 15 percent reduction in circuit load during events.

RBRP—Rolling Blackout Reduction Program (SDG&E only): Offers energy credits for load reductions—obtained through self-generation—during Stage 3 system conditions. Fifteen minute response is required.

AP-I—Agricultural and Pumping Interruptible (SCE only): Provides energy credits on consumption above the contracted firm service level in exchange for emergency reductions. Per kWh penalties apply for non-compliance.

"Emergency" CPP and DBP—these programs operate the same as the CPP and DBP programs except that notification to customers is made day-of instead of day ahead. Incentives reflect the higher value of the load reduction.

Smart Thermo—Smart Thermostat (SCE and SDG&E): Customers with communicating, programmable thermostats receive a bill incentive to allow the utilities to set their thermostats higher during periods of high demand or system emergencies.

Planning Reserve Margin Calculation

The planning reserve margin is calculated in a similar manner as in CPUC resource adequacy proceedings. The formula used to calculate the planning reserve margin is: ((Total Net Generation + Demand Response + Interruptible) / Demand)) – 1.